February 23, 2005

Mr. Gregg R. Overbeck
Senior Vice President, Nuclear
Arizona Public Service Company
P. O. Box 52034
Phoenix, AZ 85072-2034

SUBJECT: PALO VERDE NUCLEAR GENERATING STATION (PALO VERDE), UNIT 3 - SUMMARY OF CONFERENCE CALL REGARDING STEAM GENERATOR TUBE INSERVICE INSPECTION (TAC NO. MC4292)

Dear Mr. Overbeck:

Inservice inspections (ISIs) of steam generator (SG) tubes play a vital role in assuring that adequate structural integrity of the tubes is maintained. As required by the plant technical specifications, reporting requirements range from submitting a special report within 15 days following completion of each ISI of SG tubes that identifies the number of tubes plugged and/or repaired, to submitting a special report within 12 months following completion of the inspection that provides complete results of the SG tube ISI.

Telephone conference calls were held on October 21 and November 5, 2004, with members of your staff to discuss the results of the SG tube inspections conducted during the Palo Verde, Unit 3, fall 2004 refueling outage. Enclosed is a summary of the telephone conference calls. This letter and its enclosure completes TAC No. MC4292. The staff will review the SG ISI summary report associated with this refueling outage, when submitted, as a separate activity.

Sincerely,

/RA/

Mel B. Fields, Senior Project Manager, Section 2
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. STN 50-530

Enclosure: Summary of Telephone Conference Calls

cc w/encl: See next page

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SUMMARY OF STEAM GENERATOR TUBE INSPECTION

TELEPHONE CONFERENCE CALLS ON OCTOBER 21 AND NOVEMBER 5, 2004

PREPARED BY THE OFFICE OF NUCLEAR REACTOR REGULATION

ARIZONA PUBLIC SERVICE COMPANY

PALO VERDE NUCLEAR GENERATING STATION, UNIT 3

DOCKET NO. 50-530

On October 21 and November 5, 2004, the Nuclear Regulatory Commission (NRC) staff participated in telephone conference calls with representatives from Arizona Public Service Company (APS or the licensee) to discuss the scope, results, and status of their ongoing steam generator (SG) tube inspections for Palo Verde Nuclear Generating Station (Palo Verde), Unit 3.

To facilitate the October 21, 2004, telephone conference call, APS submitted a preliminary briefing paper (ML050490053) which addresses many of the discussion points contained in a NRC letter to the licensee dated September 16, 2004 (ML042600207). In addition to the written material provided by the licensee, the following additional clarifying information was discussed during the telephone conference call.

> One plug was identified with evidence of potential leakage. This plug is located in the region of the SG referred to as the "cold-leg corner." Plugs in this region are difficult to weld because of geometric constraints. As a result, there have been other instances where potential leakage from plugs in this region has been identified. No cracking has been associated with these potentially leaking plugs, and the cause of any leakage is postulated to be from porosity of the welds. In this particular case, there was a 360E ring of boron deposits on this plug. The boron was cleaned off. Upon reformation of the boron ring, it encompassed approximately 15E to 20E of the circumference. This plug is scheduled to be replaced.
>
> Rotating probe inspections are performed in the upper bundle region on the cold-leg side of the SG in response to finding indications at the cold-leg tube supports in Palo Verde, Unit 1, during the 1R10 outage in 2002. These indications in Unit 1 were initially found by bobbin coil. To ensure that freespan cracking in the cold-leg is not going undetected, the licensee implements a sampling program with a rotating probe. No freespan cracks were detected in Unit 1 during 1R10 or 1R11 (2003) as a result of these inspections. In addition, no freespan cracks were detected in Palo Verde, Unit 3, during 3R10 (2003) or 3R11 (2004) as a result of these inspections.
>
> The critical area region for the U-bends is considered rows 1 through 3. Rows 4 and 5 are considered a buffer zone. The U-bend region of all row 1 through 5 tubes were

ENCLOSURE

examined with a rotating probe equipped with a +Point™ coil. A mid-frequency and high-frequency probe are used during these examinations.

All distorted support indications and non-quantifiable indications identified by either the primary or the secondary data analyst are inspected with a rotating probe.

No in-situ pressure testing of the SG tubes was performed during the 2004 outage since no flaws exceeded the pre-screening criteria. The licensee attributes the relatively good performance (i.e., not finding flaws that require in-situ pressure testing), in part, to the chemical cleaning performed in a prior Unit 3 outage.

Unit 3 has smooth bore tubesheet holes.

With respect to the number of tube flaws found during the inspection, the licensee provided an update to the table they provided in support of the telephone conference call. At the time of the telephone conference call, the licensee estimated that they would need to plug approximately 94 tubes in SG 31 and 97 tubes in SG 32.

The increase in tube plugging in SG 31 was a result of adding approximately 10 tubes with batwing stay cylinder (BWSC) wear, one single volumetric indication (SVI), and three geometry indications. Although the BWSC flaws are slow growing, the licensee implements an administrative plugging limit of 20 percent through-wall for these flaws. Geometry indications are indications that can mask flaws. In the U-bend region of small radii tubes (rows 1 through 5), all geometry indications are plugged. This practice was instituted as a result of observing a small primary-to-secondary leak of approximately 5 to 6 gallons per day (gpd) which was attributed to a geometry indication in the U-bend region of a row 1 tube in 1997. The geometry indication was at the apex of the bend and appeared dent/ding-like in appearance. The one tube identified in the licensee's written material as being scheduled to be plugged for a dent indication in SG 31 is being plugged since an effective inspection could not be performed at this location. This particular dent is large in magnitude and is located near the fourth vertical strap in a low row tube.

The increase in tube plugging in SG 32 was a result of adding 3 tubes with degradation with depths greater than 40 percent through-wall (for a total of 4), 10 tubes with single/multiple axial indications at the first hot-leg tube support outside the arc region (for a total of 13), 2 tubes with single/multiple axial indications at the eggcrate tube support outside the arc region (for a total of 5), and 5 tubes for SVIs.

The "arc region" is a region in the upper part of the tube bundle where dryout and sludge deposition can occur. This region is determined based on thermal hydraulic models and empirical review of inspection data. All of the single/multiple axial indications in the arc region in the cold-leg were at tube supports and are attributed to outside diameter stress corrosion cracking. Two of the three indications were easily detectable by bobbin. The third indication was only detected with a +Point™ coil; however, it was small.

The licensee performs rotating coil examinations of select tubes that are outside the arc region to confirm that the arc region is adequate (since it is based on theoretical and

empirical data). The tubes selected for these exams typically have indications in other locations so the detected indication along with the portion of the tube in the upper bundle region are inspected with a rotating probe. The upper bundle region of approximately 400 tubes per SG are typically examined with this approach. During these examinations, two tubes with small freespan indications that were not detected during the bobbin probe examination were identified in SG 32 (Row 64 Column 11 and Row 63 Column 10). Because of the size of these indications, it was not expected that these flaws would be detected with a bobbin coil probe. Nonetheless, additional tubes neighboring the arc region were inspected in the upper bundle region with a rotating probe. These additional examinations focused on tubes with long unsupported lengths in the upper bundle region (e.g., several tubes in rows 60 through 70 are supported only by the seventh hot-leg tube support and the third vertical strap in the upper bundle region). These long unsupported lengths could result in tube bowing and could lead to the development of freespan cracking. No additional freespan indications were detected as a result of these additional rotating probe examinations; however, one small indication was detected at the eighth hot-leg tube support. Since this indication was small, it was not expected to be seen with a bobbin probe.

All of the indications scheduled to be plugged for depths greater than 40 percent through-wall had been detected in prior outages and are only slightly greater than 40 percent through-wall.

Of the 9 SVIs scheduled to be plugged, 8 are attributed to tube-to-tube wear. There is some evidence of change in these signals since the prior inspection and these particular indications are estimated to be approximately 20 percent through-wall. The administrative plugging limit for this type of indication is 35 percent through-wall; however, these tubes will be plugged. The ninth SVI was designated as a pit and may have changed since the prior inspection.

The licensee was projecting to plug approximately 50 tubes for single and multiple circumferential indications in the hot-leg tubesheet region; however, only 7 tubes (2 in SG 31 and 5 in SG 32) were identified. All of the indications in SG 31 were at the expansion transition. In SG 32, the indications were located on the portion of the tube within the tubesheet.

For tubes with wear indications attributed to loose parts (PLI), APS indicated that they perform rotating probe exams on surrounding tubes to determine the extent of condition. If a loose part cannot be removed from the SG, all PLIs are plugged and stabilized regardless of the depth of the tube degradation. Of the 4 PLIs detected during the 2004 outage, 3 of the 4 were located in the periphery of the tube bundle near the top of the tubesheet on the cold-leg side of the SG. All three of the indications were at the same axial elevation above the top of the tubesheet. Because these tubes were dented by the part, no reliable depth estimates could be made. The fourth PLI was located near the flow distribution plate. There was no dent at this location and the depth of the degradation was estimated to be less than 10 percent through-wall. The part could not be retrieved due to the location of this indication.
During the foreign object search and retrieval, an allen head set screw (2-inches in diameter, 5-inches long) was identified in the annulus region of one of the SGs. The part was not present in the annulus during the last outage. Given the size and location

of the part, it is unlikely that the part entered the SG through the feedwater system or that it dropped from a region above the tube bundle. This part most likely resulted in the 3 PLI indications discussed above. The part was removed and this finding was put in the corrective action program. At the time of the October 21, 2004, telephone conference call, the licensee was in the process of determining the source of the part.

Based on the preliminary inspection information, the as-found conditions were generally bounded by the projections based on previous inspection data. The number of flaws observed at the hot-leg top of tubesheet region was less than expected; however, the number of flaws in the arc region was more than expected. The increase in the number of flaws in the arc region was attributed to the recent chemical cleaning at Unit 3. Immediately following the chemical cleaning, there was no dramatic increase in the number of indications (as observed at other plants). As a result, the number of flaws projected for this cycle may have been artificially reduced since no inspection transient was observed in the prior outage. Although more indications were detected, the size of the indications were much smaller than in the past. For example, the mean voltage of the Unit 3 indications is approximately 0.5 volts (with a standard deviation of 0.12) whereas the mean voltage of the Unit 1 indications is approximately 0.8 volts (with a standard deviation of 0.3). Overall, the number of tubes projected to be plugged based on previous inspection data match the actual number of tubes to be plugged this outage. In addition, the severity of the indications detected during the 2004 outage was less than what was expected.

At the time of the October 21, 2004, telephone conference call, SG tube plugging was on-going. The licensee was planning to drill out and replace the leaking welded plug and perform the foreign object search and retrieval in SG 31 on October 23, 2004. Tube plugging was expected to be completed early the following week.

On November 5, 2004, the staff had a subsequent call with the licensee to discuss their assessment and corrective actions in response to finding an allen head set screw in SG 32. To facilitate the telephone conference call, the licensee provided a set of slides which are publicly available (ML050490124). In addition to the written material provided by the licensee, the following additional clarifying information was discussed during the telephone conference call.

The allen head set screw weighs approximately 4 pounds, has 8 threads per inch, has a hex head, and exhibited no signs of erosion or corrosion. The set screw resulted in some small amount of denting to a few tubes and the wear associated with the screw (loose part) was estimated to range from approximately 5 to 30-percent through-wall. The depth estimates of the wear are considered approximate since the dent is influencing the wear signal. The damage caused by the set screw occurred during the last operating cycle, since the set screw was not in the SG during the prior tube inspections (foreign object search and retrieval was performed during the prior outage and the set screw was not present). The tubes affected by the set screw were plugged and stabilized. In addition, the cold-leg top of tubesheet region of the surrounding tubes (approximately 23 tubes) were inspected with a rotating probe to determine if any additional tubes were affected by the set screw.

The set screw came from the feedwater box. The design function of these set screws is to prevent the feedwater box from collapsing during a feedwater line break. The screw

is inserted through the feedwater box and comes within approximately 0.25-inch of the SG shell. There is approximately 3-inches of clearance between the tube bundle and the other end of the set screw.

The feedwater box consists of two 90-degree sections with eight set screws per section. Each section has an deflector plate associated with a feedwater nozzle. When the water comes into the SG, it is directed around the feedwater box by the deflector plate. The water then goes down through the feedring holes and into the bundle of the SG. The feedring holes are approximately 2-inches in diameter (similar to the diameter of the set screw).

The set screw that became loose was located directly above one of these feedring holes and is postulated to have fallen through the hole down onto the tubesheet (i.e., the set screw fell between the feedwater box and the shell and then dropped to the tubesheet through a feedring hole). An inspection of the each of the set screws in each SG were performed and all other set screws were still in place. The holes associated with the missing set screw and the other set screws adjacent to the deflector plates (set screws 4, 5, 12, and 13) exhibited some minor erosion/corrosion. The other set screws (i.e., those further away from the deflector plate) did not exhibit signs of erosion/corrosion. Of the set screw holes next to the deflector plate (i.e., those exhibiting erosion/corrosion), only set screws 5 and 13 are directly above a feedring hole.

At the location of the missing set screw, there was no evidence that the screw scraped the SG shell. Some of the feedring holes exhibited minor erosion/corrosion. Several tubes at cold-leg tube support 02C had exhibited wear (i.e., tube support wear) possibly due to the flow streaming through the missing set screw hole.

The licensee decided to perform an analysis in which four areas were addressed: feedwater box integrity, streaming flow through the screw hole, loose part wear, and Unit 1 operability. The results from these analysis are summarized in the material provided by the licensee. As a result of these investigations, the licensee plugged and stabilized many tubes in Unit 3. For example, they plugged and stabilized a minimum of 20 tubes per SG to address water streaming through a hole from a set screw that has fallen out (i.e., they postulated that other set screws would fall out leaving a hole in the feedwater box). The water streaming from a missing set screw hole could affect the position of the tube support (lattice bar) and could result in tube wear. In the event one of the potentially affected tubes was already plugged and not stabilized, the tubes surrounding this tube were plugged and stabilized. In addition, the licensee elected to plug and stabilize tubes in the periphery within the expected transport area of the set screw adjacent to the deflector plate (i.e., those that have experienced erosion/corrosion). Given the plugging and stabilizing for other considerations (e.g., water streaming), the licensee expected to plug and stabilize approximately 6 additional tubes in SG 32 and 17 tubes in SG 31 to address this issue.

In addition to the above, the licensee indicated that they have an administrative primary-to-secondary leak rate limit of 50 gpd. There is currently no primary-to-secondary leakage in Unit 1. The SGs in Unit 1 are scheduled to be replaced in the fall of 2005. The SGs in Unit 3 are scheduled to be replaced after two more operating cycles

(approximately fall of 2007). The set screws discussed above are used in plants with economizers (i.e., preheaters). Of the plants with Combustion Engineering SGs, only Palo Verde has an economizer. The replacement Palo Verde, Unit 2 SGs also have an economizer with a similar “set-screw” configuration. The replacement SGs for Palo Verde, Units 1 and 3 will also have this configuration. The licensee indicated that they were evaluating the need for future inspections in the replacement SGs. The licensee also indicated that they did not expect any impact on SG performance as a result of the missing set screw (e.g., no increased wear in the bat-wing region above the stay cylinder).

At the time of the November 5, 2004, telephone conference call, the licensee was still finalizing some of their analysis and indicated that if it changed, they would inform the NRC staff.

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